REACTOR OVERSIGHT PROCESS
LESSONS LEARNED PUBLIC WORKSHOP
(March 26 - 28, 2001)
MEETING MINUTES

On March 26 - 28, 2001, the NRC conducted a public workshop to bring together the NRC and external stakeholders to discuss, review, and develop recommendations associated with key issues that have emerged during the first year of initial implementation of the new Reactor Oversight Process (ROP). This document describes issues and their background going into the workshop, additional issues raised at the workshop, and the workshop outcomes. Also included is a response to questions that were raised at the workshop but were not answered due to time constraints. NRC's response to these questions reside in the appropriate subject matter area; however, miscellaneous questions are addressed at the end of the meeting minutes. Questions regarding the meeting minutes should be addressed to Fiona T. Tobler at ftt@nrc.gov or 301-415-8473

REACTOR SAFETY PERFORMANCE INDICATOR (PI) ISSUES
MEETING MINUTES
(March 26 - 28, 2001)

ISSUE 1: SAFETY SYSTEM UNAVAILABILITY PI

NOTE: The Nuclear Energy Institute (NEI) formed a working group that established a strawman to propose changes to the Safety System Unavailability (SSU) PI used in the Reactor Oversight Process (ROP). The NRC established a Focus Group to recommend near-term improvements to the SSU indicators for a future revision of NEI 99-02. The NRC's proposal was intended to provide meaningful and appropriate indication of the availability of monitored systems until Risk-Based Performance Indicators (RBPI) are developed by the NRC's Office of Nuclear Regulatory Research. The two groups worked independently, then met jointly to discuss their results. The outcome of these efforts is described in the Proposed Resolution sections below.

ISSUE 1A: What unavailable hours should be included in the SSU PI?

a. Should all unavailable hours of a train be counted whenever the <u>function</u> is required, or only when the train is required?
b. Should on-line maintenance be excluded from the SSU if the licensee has a risk analysis that shows the increase in risk is small?
c. Should support system unavailable hours be counted as monitored system unavailable hours?
d. Should unavailable hours due to design deficiencies be excluded from the SSU PI?

BACKGROUND:

a. The SSU PI was derived from the WANO Safety System Performance Indicator (SSPI). The WANO SSPI (and consequently the ROP SSU) does not include unavailable hours that occur when a train is not required to be operable by Tech Specs, even though the function may be required. For example, in cold shutdown, refueling or defueled, only one train of emergency ac power is required. Any maintenance, including overhaul, on another train is not included in the SSU calculation for that train. Should all unavailable hours of a train be counted whenever the <u>function</u> is required, or only when the train is required?

b. There was a perceived unfairness in counting unavailable hours for licensees that perform on-line maintenance in accordance with a risk-informed tech spec change that extended the allowed outage time for that purpose, because off-line maintenance is not counted and the risk is comparable. Should on-line maintenance be excluded form the SSU if the licensee has a risk analysis that show the increase in risk is small?

c. The WANO SSPI includes unavailable hours for a monitored system when support system unavailability (except emergency ac power) renders the monitored system unavailable. Should such support system unavailable hours be counted as monitored system unavailable hours? If so, what requirements would be placed on the support system to assess unavailability of the monitored system, e.g., must the support system be single failure proof and/or meet all design basis requirements?

d. Design deficiencies can manifest themselves years later. The time of failure would normally be known and could produce large fault exposure hours that could result in a non-green PI for up to three years. To avoid such a situation, the ROP excludes design deficiencies from the PI calculation. Should unavailable hours due to design deficiencies be excluded from the SSU PI?

ISSUE 1B: How should start and run failures be handled in the SSU?

a. Is a reliability indicator necessary, or can the SSU alone provide meaningful indication of safety system performance?
b. Should estimates of fault exposure hours be used in lieu of an unreliability indicator? Are there acceptable alternatives?
c. Should the ROP include a provision to allow licensees to remove large increments of fault exposure hours after one year if the NRC has approved the licensee's corrective actions?

BACKGROUND:

The WANO SSPI does not use an unreliability indicator. Instead, WANO incorporates unreliability into the SSU through the use of fault exposure hours (FEHs) associated with a train failure (although not explicitly stated, the failure should include run failures as well as start failures). If the time of discovery of the failure is known but the time of failure is not known, the fault exposure time is taken as one-half the time (t/2) since the last successful test or operation of the train. The problem is that the t/2 estimate will usually dominate the unavailable hours. Should estimates of fault exposure hours be used in lieu of an unreliability indicator? Are there acceptable alternatives to the use of estimated FEHs, such as using a baseline inspection to assess the risk of start and run failures? Or should an unreliability indicator be developed for use prior to the completion of the RBPI effort? If an unreliability indicator is used, how are FEHs then used for discovered conditions, such as a closed manual valve in the injection path of a monitored system?

A large increment of fault exposure hours, such as might occur due to a failed surveillance test of 30 days or longer interval, could result in a non-green PI for up to three years. This creates two concerns. First, any additional problems in that train could be masked, since the white band is from one to three times the width of the green band, so that another threshold might not be crossed to trigger additional NRC engagement. Second, after some period of time, the PI is no longer indicative of current performance. For these reasons, a provision has been added to the ROP SSU to allow licensees to remove large (@336 hours) increments of FEHs due to a single event or condition after one year if the problem has been corrected and the NRC Region has approved the resolution. Should the ROP include a provision to allow licensees to remove large increments of fault exposure hours after one year if the NRC has approved the licensee's corrective actions?

ISSUE 1C: What credit should be allowed for operator recovery actions?

BACKGROUND:

The SSU allows credit for operator actions to restore a train when a demand is received during surveillance testing if the actions are virtually certain to be successful. Licensees have requested credit for operator actions to recover from uncomplicated maintenance configurations, and from more complicated maintenance or test configurations when there is sufficient time until the train is required by the accident analysis. Probabilistic Safety Analyses include probabilities of operator recovery actions as important components in the progression of any accident scenario. In the ROP, credit has been limited because the SSU PI measures equipment performance, not operator performance. If the recovery actions are virtually certain to be successful, then the probability is near 1 and credit can be given. Anything short of 'virtually certain' requires estimation of a number less than 1, which is likely dependent upon the situation, the crew, and perhaps the specific operator involved. Therefore no credit is given. Maintenance activities conducted during chaotic conditions in the course of an analyzed accident are not considered to be virtually certain. Should the SSU allow credit for operator actions that are virtually certain to be successful? Should there be credit allowed for more complicated recovery actions? If so, what conditions should be applied to such actions?

ISSUE 1D: Should default values for hours a train is required be allowed?

BACKGROUND:

The calculation of the SSU uses, as the denominator in the calculation of train unavailability, the hours the train was required during the most recent 12 quarters. The WANO guidance has allowed licensees to estimate this number through the use of default hours to reduce the data collection burden on licensees. In some cases, the default value is non-conservative in that the denominator would be larger than the actual required hours. This will cause the calculated value to be lower than the true value. In the case of the EDG SSU, the error could be as much as 60 percent. Should the ROP allow licensees to use the non-conservative default hours approved by WANO? If not, is there an acceptable alternative estimate?

OUTCOME OF ISSUES:

There was agreement that, in the ideal world, the performance of mitigating systems would be monitored by both an unavailability indicator and a reliability indicator. However, it will take additional work before we achieve that goal. NEI made a proposal to not count unreliability against SSU, but to run the issue through the SDP. The NRC is considering how such an approach could be implemented. There was also agreement that operating and shutdown performance should be monitored separately and that all unavailable hours should be counted during power operation. There were differences of opinion on how to count support system unavailable hours and unavailable hours due to design problems. There were also differences on credit for operator action and the use of engineering analyses. Proposals were made to link the SSU thresholds to maintenance rule criteria and to strive for common definitions for unavailability. The discussion on the use of default values for the hours a train is required identified the need to develop parameters that could be used by licensees to determine when the use of default values is acceptable. There was discussion on the appropriateness of it to determine train unavailability.

ISSUE 2: UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS PI

For this PI, "unplanned power changes" is defined as "changes in reactor power that are initiated less than 72 hours following the discovery of an off-normal condition that require a change in power level of greater than 20% of full power to resolve." Licensees have, in some instances, deferred maintenance beyond 72 hours to avoid a count in this indicator. There are also instances where licensees have modified operating procedures to limit power reductions for equipment problems to less than 20% avoid a count in this indicator.

BACKGROUND:

This indicator was patterned after the unit shutdowns and power reductions reported in licensees' monthly operating reports (MOR). It is used because the NRC has observed that plants that run smoothly, with few changes in reactor power, tend to be safer plants. There is a reasonably good correlation between plants with many unintended changes in reactor power and plants the NRC has in the past placed on the watch list or sent declining trend letters. The definition of a forced power reduction in the MOR was not used in this PI because of industry concerns that the definition does not accurately reflect the time required to adequately plan a power reduction, and because deregulation could affect the number of power reductions to address equipment problems that licensees undertake. However, the MOR definition is unrelated to the time required to plan a power reduction. It was intended to identify power reductions that were required to be conducted at the earliest opportunity, which was historically considered to be the next weekend after discovery of the off-normal condition. Power reductions in and of themselves require very little planning; planning is required for the work to be conducted during the power reduction, something that is not related to the purpose of this indicator. The 72 hour period is the sole factor in determining whether a power change is planned, not the extent of planning that is performed. Because the time to adequately plan the work to be done can vary considerably from one situation to another, and because the PI requires a defined change in power level (20%) to be counted, there may be, in some instances, an incentive for licensees to manage their plant to the indicator.

OTHER ISSUES RAISED AT WORKSHOP:

Consideration of other alternate performance indicators for unplanned power reductions.

Delete the word “Shutdown” from the title of the proposed unplanned power reductions performance indicator to avoid confusion.

OUTCOME OF ISSUES:

The replacement PI will be evaluated through a pilot program. The word “shutdown” was removed from the indicator since these would be captured by power reductions. There was agreement that the thresholds would be evaluated during the pilot program. There was discussion about the unintended consequence of licensees attempting to manipulate average daily power level, but those concerns could be balanced by the financial incentives to maximize power production. It was agreed that criteria to evaluate the success of the new PI would be developed and would be included in the Regulatory Information Summary announcing the new PI. There was discussion about the purpose of the PI; one view is that the PI should measure initiating events rather than routine events causing power changes. There was a proposal for an alternate replacement PI called "unanticipated" transients that would count equipment malfunctions and human errors but not Technical Specification surveillances requiring a downpower, such as MSIV testing, BWR rod swaps, or turbine valve testing. Another point of view was that the more complicated the guidance is, the more Frequently Asked Questions would be generated and greater confusion would exist in the interpretation of the reporting requirements. Some participants expressed the thought that the replacement would be worse than the current PI and that there would not be a "level playing field" in terms of the events reported, since utilities do not have the same surveillance testing requirements.

ISSUE 3: UNPLANNED SCRAMS PER 7,000 CRITICAL HOURS PI

Some industry managers perceive the potential for negative consequences from counting manual scrams. There is a potential for a negative impact on the PI program from the proposed replacement PI.

BACKGROUND:

The concern is that an operator may be influenced by the indicator to not scram the reactor when required. A new definition for a replacement indicator has been developed and is currently undergoing a pilot program. The intent of the new PI is to continue to collect the same information that is captured in the existing PI. The indicator is named "Unplanned Reactor Shutdowns per 7,000 critical hours." It does not use the word "scram," but defines an unplanned reactor shutdown as a "shutdown of the reactor in response to off-normal conditions or events by the unplanned addition of negative reactivity by any means (e.g., insertion of control rods, boron, or opening reactor trip breakers). Unplanned reactor shutdowns are those that bring the reactor from criticality to a shutdown mode within 15 minutes of commencing to insert negative reactivity." The replacement indicator may not be as clear as the current PI about what is and is not expected to be reported. It therefore has the potential to cause more confusion and questions, which could result in greater burden on licensees as well as on the NRC staff.

OUTCOME OF ISSUES:

There were no concerns raised about the replacement scram PI. However, there were concerns expressed about changes to the guidance in the proposed replacement to the Unplanned Scrams with Loss of Normal Heat Removal that would include unplanned reactor shutdowns caused by the loss of all main feedwater or loss of condenser vacuum. This would result in the reporting of more events. The NRC noted that the new words would comply more closely with the methodology used in the Initiating Events study (NUREG-5750) which was the data source for the thresholds for this indicator.

RESPONSE TO QUESTIONS NOT ADDRESSED AT WORKSHOP:

Question: A licensee was considering withdrawing a longstanding Yellow PI, which would return its findings for the previous quarters to Green. The SDP was not completed because the Yellow PI would have been greater than the significance of the associated finding. How do we handle such a situation?

NRC Response: The specific issued raised by this question is being addressed by the NRC/Industry Working Group. The process governing the reporting of the PI, including responding to PI questions and feedback, is described in Inspection Manual Chapter 0608 " Performance Indicator Program".

Question: Regarding Unplanned Power Reductions:

A. Is it possible to differentiate reductions that occur during peak demand hours and those that occur during non-peak demand hours?
B. When setting the thresholds, would it be possible to differentiate between reactor types (BWR/PWR) and vendor (GE, Westinghouse, B&W, CE, etc.)?
C. The denominator of 7000 critical hours is based on an availability of about 80% (7000 hours/8760 hours per year). Should this be changed to reflect current industry norms?

NRC Response: A. This is not possible with the data we currently collect; it would require more complicated data collection and would complicate the PI.
B. This is possible and we do it when it makes sense to - that is, when we expect there to be a difference between PWRs and BWRs, as is the case with Safety System Functional Failures, which has a threshold of 5 for PWRs and 6 for BWRs.
C. This is certainly possible. The NRC will monitor the need to do this, as well as to adjust the thresholds, as the ROP PI program matures.

Question: In the unavailability discussion, solutions to the t/2 fault exposure hour (FEH) and support system unavailability issues was communicated as 2002 implementation tied to a major change to the SSU PI. What consideration and priority is being given to implementing solutions to current PI issues in 2001? What barriers need to be removed?

NRC Response: Changes to the PI program are conducted in accordance with a procedure that is intentionally deliberate and methodical to ensure that the change is adequately reviewed. This process normally takes about one year due to the requirement to conduct a six month pilot program. There is a strong desire on the part of both the NRC and the industry to resolve these issues as soon as possible, but we must follow the procedure.

Question: Our utility has a White PI due to large fault exposure hours (FEH). An NRC supplemental inspection concluded that the issues were Green, but the PI remains White for 4 quarters anyway. Should the guidance for removal of FEH be revised such that, for issues evaluated by the SDP as Green, once all the corrective actions are completed the FEH can be removed?

NRC Response: There is an extensive effort underway to make improvements to the SSU indicators. This issue will be considered in that effort.

Question: Won't development of a reliability indicator require significant data collection (number of demands on ROP SSU key components)? This could be a significant demand on resources.

NRC Response: Both NRC and NEI recognize the data collection issues and associated resource burdens. This issue is being examined at meetings between NRC and INPO/WANO as part of improving data collection efforts for the EPIX database.

Question: Shouldn't the NUREG-1022 criteria (reporting requirements for LERs under 10 CFR 50.73) be the uniform definition that applies to determining the FEHs?

NRC Response: No. The NUREG-1022 criteria apply to reportability issues only. For example, in the event of a surveillance test failure that renders a system inoperable, and there is no clear evidence to indicate that the failure occurred prior to the test, the NUREG-1022 guidance is to assume the failure occurred at the time of the test. This is acceptable because the failure is reportable as an event that could prevent the fulfillment of a safety function, so it is not necessary for the licensee to determine if it is also reportable as a condition prohibited by the technical specifications. However, in determining unavailability of the system, it may be important to know the time of failure, and it is therefore not acceptable to assume it failed at the time of the test (see NEI 99-02, Rev. 0, page 22, line 40).

Question: FEH are better considered in the SDP than the PIS. Shouldn't FEH be removed from the SSU Performance Indicators?

NRC Response: Fault exposure hours are used in the SSU indicators in two ways. One way is to incorporate some measure of failures on demand - either a demand to start or a demand to run for the mission time. Such events are more appropriately captured by a reliability indicator. The other way is to incorporate a measure of the time that a train could not perform its safety function because of a pre-existing condition. Such conditions are appropriately captured by an unavailability indicator. Consideration is being given to removing the first type of FEH from the SSU, but the second type would remain.

Question: As a utility member, it seems like the new proposed change to include reactor shutdowns within 15 minutes may require additional data to be collected that is not collected now, such as the length of time from 100% power to shutdown.

NRC Response: The requisite data may not be captured explicitly in plant logs, but it should be available on strip chart recorders and the plant computer.

Question: The Performance Indicators will need to address that fact that deregulation will cause some business decisions to be made where a utility will choose to run for a period of time at a reduced power level so as to move the next refueling outage out of a high demand/price period, or allow operation during high price periods.

NRC Response: The NRC and NEI will continue to reevaluate all aspects of the PI program to identify changing conditions that affect PI reporting and thresholds and to adapt to those changes. In general, the Performance Indicators are intended to capture important aspects of safety performance. There is no intent to cause licensees to change operating practices.

Question: Inordinate amounts of time are being spent on the safety system function and failure (SSFF) and unavailability Performance Indicators because of loose definitions. The "safety function" being met is the biggest problem because there is not clear docketed information on what the "safety function" of a structure, systems and components (SSC) is. Couldn't we save this burden by using plant Technical Specifications to determine operability and availability, then adjust the thresholds accordingly. The data for this PI was gathered when there was no incentive to do extensive engineering analysis to prove that a safety function was met.

NRC Response: The definition of an SSFF is the same as that in 10 CFR 50.73 (a)(2)(v), and the SSU was taken from the WANO Safety System Performance Indicator. It was expected that licensees would therefore be rather familiar with both of these Performance Indicators. However, experience has shown that there have been problems with both of them. An extensive review is underway to simplify the SSU, and consideration is being given to ways to simplify the SSFF.

Question: Define the appropriate number of significant digits in NEI 99-02. While established in the database, it is not captured in writing.

NRC Response: NEI 99-02, Table 1, identifies the number of significant digits required of each PI value. Data used in the calculations of the Performance Indicators should be as accurate as necessary to obtain the required PI accuracy. Note that place-holding zeros are not significant digits.

Question: Remove the wording in NEI 99-02 discussing the necessity of primary and backup Shut Down Cooling (SDC) methods. This is not a specific Technical Specification requirement in (at least) CE plants. Typically, 1 train of SDC is removed during refueling outages with "time to boil" estimates monitored if SDC is lost. Lines 35-39 should be replaced with wording such as: "For specific instances where RHR trains are removed following approved evolutions outside of technical specifications, alternate methods of maintaining adequate shutdown cooling may be credited without incurring unavailable hours. These methods must be analyzed to verify that 100% of the decay heat expected can be removed."

NRC Response: This may be a CE plant-specific Appendix D issue. A working group is still evaluating the requirements for SDC trains.

FIRE PROTECTION ISSUES
MEETING MINUTES
(March 26 - 28, 2001)

ISSUE NO. 1:

Improvements need to be made to the fire protection Significance Determination Process (SDP) to make it more effective and efficient to use. Those improvements are to develop tools or improve guidance in (1) fire scenario development, (2) fire frequency data, (3) fire brigade evaluation, and (4) evaluation of manual actions.

BACKGROUND:

The need for these improvements has become apparent through using the fire protection SDP to evaluate fire protection inspection findings. The Individual Plant Examination of External Event (IPEEE) performed in response to Generic Letter 88-20 Supplement 4, and NUREG-1407, have shown that fire is a significant contributor to Core Damage Frequency (CDF) in a majority of plants. In some cases, fire contribution to CDF can approach (or even exceed) the contributions from internal events.

(1) Currently, fire scenarios are developed qualitatively, without the benefit of quantitative tools. Fire scenarios development needs to become more scientific and less subjective. Also, availability of such a tool would assure consistency across the Regions.

(2) A need exists to improve the quality and availability of fire ignition frequency data. The NRC's latest study used data up through 1994, and is out-of-date. Currently, fire frequency input is a significant factor in the risk-informed analysis and the data should be as current as possible to provide the most accurate assessment.

(3) There needs to be a mechanism to improve the validity and objectivity of the evaluation of fire brigade performance for use in the SDP. Currently, fire brigade drills are not conducted during the triennial inspection. Since the triennial inspection team does not observe a drill, it is difficult or impossible for them to determine the level of degradation of the fire brigade.

(4) The current SDP does not account for the feasibility and effectiveness of human actions unique to fire scenarios. Inspectors are identifying special circumstances due to fire that need to be taken into account in the SDP evaluation of human actions.

ISSUE NO. 2:

The plant fire protection licensing bases and approved processes for changing them are not always clear to inspectors and licensees. This complicates performing fire protection inspections because we often disagree with the licensees on the exact licensing basis for the plant and such issues tend to be difficult to resolve.

BACKGROUND:

a. Resolving Licensing Basis Issues: Plant fire protection licensing bases often involve differing interpretations, requiring NRR resolution. Some involve potentially generic issues for which TIAs or other vehicles may be written. The current system for resolving generic issues has the following shortcomings:

1) The resolution path and status of generic issues are not always readily available to inspectors. This complicates regional resource planning for ultimate generic issue closeout, requires unnecessary expenditure of effort contacting the program office for generic issue status, and does not promote efficient communication between the regions and NRR on issues.

2) Accountability may be lacking on some issues. This increases the likelihood of an issue dropping through the cracks during the handoff between the regions and NRR.

> a. Changes to licenses: Many licensees have modified their facility, by removing fire protection features (e.g., Thermo-Lag) and substituting additional manual operator actions, using the 50.59 process. Since fires are not postulated to occur during accidents evaluated in the UFSAR, licensees could potentially remove almost all fire protection features under 50.59. In addition, not all licensees have thermal-hydraulic time lines or other analysis techniques to support the use of these manual actions. Also, licensees may not be appropriately following their license condition requiring that changes to the fire protection program do not adversely affect safe shutdown. Finally, licensees may not be following requirements of GDC 3 and 50.48. Inspectors have not been trained on and may not understand the legal requirements of the term "adversely affect," GDC 3, and 50.48 with respect to inspecting changes to the facility made by the licensee.

OTHER ISSUES RAISED AT THE WORKSHOP:

During the Fire Protection breakout session participants indicated that the following additional issues should also be addressed by the NRC:

Consider use of licensee self assessment. Discussion: Several licensees felt that NRC inspectors should, at least in part, consider licensee evaluations of fire brigade capability as an input to the SDP when needed.

Too much emphasis on safe shutdown and not defense in depth. Discussion: The inspection procedure guidance emphasizes the importance of inspecting alternate shutdown capability over the inspection effort committed to evaluate the adequacy of defense in depth components, such as automatic detection and suppression, fire barriers, etc.

Faster resolution of issues for public confidence. Discussion: Difficulties encountered by inspectors and licensees to clarify fire protection design bases, combined with the complexities associated with the application of the fire protection SDP, delays the issuance of the triennial fire protection inspection reports

OUTCOME OF ISSUES:

The NRC will evaluate developing a quantitative tool (spreadsheet) to be used as part of the SDP for fire scenario development to limit subjectivity and improve overall consistency. This tool is intended to enhance the inspectors' capability to establish fire scenario boundaries, estimate fire loads, and calculate maximum hot gas layer temperature associated with the fire scenario.

The NRC will evaluate updating fire ignition frequency data to capture information thru 2000 to ensure that assumptions used in risk estimations reflect current industry performance and ensure that plant-specific data is factored into plant specific analyses when actual plant performance deviates from industry averages.

The NRC will evaluate changes to inspection guidance to improve the validity and objectivity of the evaluation of fire brigade drill performance by:

a. Providing additional guidance to inspectors on evaluations of fire brigade performance during drills,

b. Considering the feasibility of establishing a fire brigade drill performance indicators and the use of licensee self-assessments as inputs to the process for evaluating overall brigade effectiveness and,

c. Ensuring that fire brigade performance is not judged on the basis of only one drill.

The NRC will consider developing a process which evaluates human performance and provides a quantitative basis for the significance determination.

The NRC will continue to communicate with external stakeholders prior to implementing revisions to the current SDP guidance.

The NRC will formulate additional guidance to inspectors on how to evaluate the use of manual actions when credited by the licensee, in lieu of automatic actions/passive devices for compliance with license commitments and continue to improve how the NRC inspects and evaluates the adequacy of changes to fire protection programs.

Given all the proposed actions, the industry emphasized that the revisions should not increase the complexity of the SDP.

RADIATION SAFETY ISSUES
MEETING MINUTES
(March 26 - 28, 2001)

PUBLIC RADIATION SAFETY

ISSUE 1:

Change to the Transportation section of the PUBLIC RADIATION SAFETY SDP.

OUTCOME:

A summary was provided on a change that was made to the Transportation section of the SDP. This portion of the SDP assesses the risk from the failure of a licensee to correctively classify a radioactive waste shipment. In the Transportation / 10 CFR Part 61 section (i.e., classification of radioactive materials for shipment and disposal); the NRC evaluated a proposed revision to the Part 61 portion of the SDP that was submitted by NEI on June 12, 2000. The issue involved a situation where there is a failure of a licensee to correctly classify a radioactive waste shipment. Specifically, where a licensee under classifies the waste by assigning it a Class A designation, when it was actually Class B waste. NEI proposed that the SDP flowchart be expanded to offer extra decision diamonds to refine the process into separate steps which correspond to different levels of "risk" to the public. Prior to the change, all findings which involved radioactive materials being under classified received a WHITE finding. NEI maintained that there are cases where there is low risk to workers, members of the public, the waste disposal facility, and the environment. For such cases, the SDP should reflect this low risk and the SDP be changed to include a risk assessment of GREEN. The NRC agreed with the proposed revision. There was agreement among Stakeholders that a WHITE finding was still appropriate for cases which involved Class C waste and for Class B waste that did not meet the requirements of 10 CFR 61.56.

The staff evaluated the proposal and agreed that it provided an appropriate level of risk assessment for the issue. The staff incorporated the change into Manual Chapter 0609,
Appendix D.

ISSUE 2:

Radioactive Material Control section of the SDP.

OUTCOME:

A summary was provided on draft guidance to NRC Inspectors to provide clarification on the adequacy of licensee controls to assure that licensed radioactive material is properly controlled and not inadvertently released offsite.

There has been feedback from industry and NRC inspectors that additional guidance is needed in this area to clarify when a licensee has "lost control" of its licensed radioactive material while it is still on a licensee's owner controlled property. The staff drafted additional guidance, for inclusion in the

SDP, for stakeholder review and comment (see Attachment X). The guidance provides for licensees to be given credit for situations where the radioactive material is discovered outside of the radiation controlled area of the facility but still in an owner controlled area. To receive the credit, the radioactive material would have to pass through a radiation survey point, that is capable of detecting the material, prior to being "free released" from the licensee's control. The guidance recognizes the licensee's final radiation survey point as an effective barrier to prevent the radioactive material from being inadvertently released from the plant site.

This guidance will be incorporated into Manual Chapter 0609, Appendix D during the next review cycle.

ISSUE 3: Time frame to be used for counting radioactive material control occurrences is inconsistently applied.

OUTCOME:

A summary was provided on the development of a set time frame to be used for counting radioactive material control occurrences. The SDP for Radioactive Material Control assigns a WHITE finding to a licensee's program when there are more than five radioactive material occurrences in the two year inspection cycle of Inspection Procedure 71122.

This issue has been discussed with Stakeholders. Two options are being considered: a two year window with rolling quarters or a fixed two year window. The current consensus was to use a two year window with rolling quarters. This option is consistent with that used for evaluating Performance Indicators.

This issue will be discussed a future public meeting to obtain stakeholder input prior to incorporating the criteria into Inspection Procedure 71122.

OTHER ISSUES RAISED AT WORKSHOP:

Parking lot issue: Radiation doses to members of the public inside protected areas from radioactive materials evaluated by the Radioactive Material Control SDP.

OUTCOME:

A question was asked if it would be a "finding" if a member of the public was on a licensee's owner controlled property and was exposed to licensed radioactive material. This question involves two different scenarios with two possible outcomes. For the situation where the member of the public was exposed to radioactive material that would be considered an occurrence in the Public Radiation Safety cornerstone SDP (i.e., where there is no final radiation survey which would prevent the radioactive material from going out of the owner controlled property); this would be a finding that would be evaluated using the SDP flowchart. The risk would be assessed based on the calculated dose to the member of the public. For the other situation where the licensee maintained control of the radioactive material on its owner controlled property, it would not be a finding. A licensee may allow members of the public onto their site. While on the licensee's site, a member of the public may receive radiation exposure from the licensed facility. The public dose limit is that contained in 10 CFR Part 20, Standards for Protection Against Radiation. Thus, any dose received by the member of the public would be evaluated against the public dose limits in 10 CFR Part 20. If no regulatory dose limits were exceeded, there would be no finding.

RESPONSE TO QUESTIONS NOT ADDRESSED AT WORKSHOP:

Question: Licensees use various types of radiation survey instruments for survey and release monitoring programs to ensure that licensed radioactive material is not inadvertently released. The detection capabilities of these instruments can vary. What are the ROP finding ramifications if one licensee releases material with one instrument and another licensee identifies that the "free released" material contains licensed radioactive material? Assume that both surveys were adequate and met the industry standard for minimum detection capabilities.

NRC Response: The situation described would be a potential violation of 10 CFR Part 20 and would have to be dispositioned in accordance with the Radioactive Material Control portion of the Public Radiation Safety cornerstone SDP. This is because, except for very specific situations cited in 10 CFR Part 20, the regulation does not contain release limits for solid materials which contain licensed radioactive material. Thus, whenever licensed radioactive material is detected, by whatever type of instrument or technique, it must be handled in accordance with 10 CFR Part 20. Therefore, licensed radioactive material that is/was not under the control of a licensee is a potential violation.

PUBLIC RADIATION SAFETY CORNERSTONE DRAFT REVISED SDP GUIDANCE

DRAFT for comment

What would and would not be a finding in the Radioactive Material Control portion of the SDP?

A contaminated item (i.e., tool, equipment, clothes, etc., but not a person) that gets out of a radiation controlled area (RCA), as long as there is a final radiation survey point (portal monitor at the guard house) that the item has to go through prior to being "free to go anywhere", is still considered to be under the control of the licensee. This type of situation would typically not be a finding because the final radiation portal has an opportunity to detect the item and prevent its free release. The licensee should be given credit for the final radiation survey. However, if the item could get out of the protected area without a radiation survey (no portal monitor or carried out in a box on a truck) or the portal is not sensitive to the item, then the item is available to enter the unrestricted area and any member of the public can be exposed to it. This would be a finding and count as an occurrence.

However, because a contaminated item got out of the RCA probably represents a non-compliance with a plant procedure, there can be two potential outcomes. For low levels of contamination, it can be a minor issue and resolved through the licensee's corrective action program. For high levels of contamination that may represent a potential risk to non-occupationally classified plant workers (i.e., member of the public), the issue should be assessed as more than minor and evaluated by the SDP.

In summary, if the licensee caught the contaminated item in their owner controlled area and there was a final radiation survey point that could detect it, and there was low risk to non-occupationally classified plant workers, then it should not be a finding. But, if there is no final radiation survey point or the radiation portal monitor was not sensitive to the contaminated item, or there was risk to non-occupationally classified plant workers, then it is a finding that should be run through the SDP, and counted as an occurrence.

To determine the number of occurrences, it is not simply the number of items that were found. The number of occurrences needs to be related to the "root cause" for the loss of control over the items. For example, a technician performing inadequate radiation surveys in which 20 contaminated items were released to the unrestricted area during one work shift; this should be counted as one occurrence with multiple examples. However, if there are a number of different root causes or one that was repetitive over time (i.e., different work shifts) that allowed multiple contaminated items to be released, then the number of occurrences should be based on the number of separate occurrences.

DRAFT for comment

OCCUPATIONAL RADIATION SAFETY

The Radiation Safety break-out session of the workshop was conducted in two segments. The first was an information exchange for those issues where the staff felt that the issues were clear and a relatively straight forward resolution was being proposed. The Public Radiation Safety issues listed above and the first Occupational Radiation Safety issue listed below were presented in this segment. Workshop participants were encouraged to comment on the proposed solutions. The second segment of the break-out session was conducted as a facilitated discussion on the several ALARA related issues. The objectives of this segment were to 1) clearly articulate the basis for the current ALARA assessment in the revised Reactor Oversight Process (ROP), and 2) develop a consensus opinion for resolutions to the noted issues or alternatively develop a course of action to resolve the issues on which alignment could be reached.

Prior to the discussion of the following issues, the NRC staff presented the basis for the current SDP, including a review of the 1) NRC Strategic goals, 2) the ROP objectives and structure, 3) the regulatory history of ALARA, and 4) a summary of the constraints and assumptions that were factored into the present version of the inspection guidance and SDP.

ISSUE 1:

The Radiation Exposure Control section of the Occupational Radiation Safety SDP can be read to exclude any exposure to a hot particle (or discrete radioactive particle) contrary to the Commission's enforcement discretion policy for skin overexposures.

BACKGROUND:

The foot note in the SDP diagram, as well as the discussion text, in MC 0609 was included to account for the interim hot particle enforcement policy concerning skin dose (shallow dose equivalent) overexposures from hot particles. However, as written the SDP appears to exclude all hot particle exposures, including whole body (deep dose equivalent) as well as skin dose from hot particles not subject to the enforcement discretion.

RELATED ISSUES RAISED AT WORKSHOP:
None

OUTCOME OF ISSUES:

The staff will revise Radiation Exposure Control section of the Occupational Radiation Safety SDP to clarify how the SDP reflects the Commission's policy on enforcement discretion for skin overexposures from hot particles (or discrete radioactive particles). The current SDP flow diagram will be revised to incorporate, as decision gates, the footnoted issues.

ISSUE 2:

Implementation of a collective does screening criteria in the ALARA portion of the SDP may result in either 1) too lenient or 2) too harsh an agency response to similar ALARA issues.

BACKGROUND:

1)The current Group two screening criteria in MC 0610* screens out all ALARA issues identified at plants that have a rolling three year average collective dose which does not exceed the screening criteria. The intent of this screen was to focus agency response to those plants with relatively poor performance. Plants that do not exceed the criteria were viewed as having an overall effective program not withstanding the individual inspection issue. The unintended consequence of this screening is that, for these licensees, a failure to implement appropriate ALARA procedures or engineering controls, cannot be documented in the inspection report. This has also raised the question " If you can not have an inspection finding at a plant, why inspect that plant at all?" In addition, some claim that the screening criteria is therefore, a defacto definition of ALARA.

2) Licensee's with three year average collective doses above the screening criteria are at risk for multiple WHITE findings (ending up in a degraded cornerstone) from one bad outage. The Callaway action has raised the question of whether a violation associated with three WHITE findings (escalated enforcement) is too harsh a response considering the agencies previous enforcement history with ALARA.

OTHER ISSUES RAISED AT WORKSHOP:

Several industry participants expressed objections to the way the current Group 2 screening criteria and SDP use the licensee's rolling-3-year average collective dose. A unanimous opinion (demonstrated by a hand vote during the discussion) of non-NRC participants, was that the rolling-3-year average collective dose should <u>not</u> be used as a basis for an inspection finding screening criterion <u>nor</u> a significance determination criterion. A proposal was made to replace the current Group 2 question with one based on the concept of an occurrence resulting in "unintended collective dose", and use the rolling-3-year average as a basis to adjust the inspection effort of a variable Baseline Inspection (a concept introduced by the secession facilitator). The other Group 2 question criteria would then be incorporated into inspection procedure guidance. Another comment indicated that the rolling-3-year average should be made more contemporaneous.

Several comments questioned what constituted an adequate basis for an ALARA performance issue. These included 1)SDP criteria should be related to identified ALARA program weakness or failure, 2)Internal logic of current SDP not consistent, in that similar failures at different plants can have different outcomes (significance), and 3) Is there a way to be objective without numerical criteria? A brainstorming session developed a list of criteria that were considered appropriate for determining the significance of ALARA performance, assuming that an occurrence resulting in "unintended collective dose" is used as the basis of an inspection finding. This list included:

1. Magnitude of the unintended dose.
2. Scope of the work activity.
3. Percentage by which the intended dose was missed.
4. Timely corrective action.
5. Repeated failures.
6. Number of occurrences.

Additional comments questioned the SDP Green/white and White/Yellow thresholds. No participant in the session could put forth a valid basis for judging a single failure in ALARA as Yellow significance. The issue of whether an ALARA program with significant breakdowns should be assessed with multiple White findings (e.g., the assessed as a Degraded Cornerstone in Occupational Radiation Protection on ALARA issues alone) was also discussed.

OUTCOME OF ISSUES:

See summary below.

ISSUE 3:

The current basis of the ALARA portion of the SDP (i.e., comparing actual does expanded to dose projection for each job) leaves it open to artificial manipulation of the outcomes.

BACKGROUND:

The SDP structure was designed to evaluate the licensee's performance in ALARA on a per job basis (e.g., as opposed to on a per outage basis, or strictly on a rolling three year average collective dose basis, etc.) In context, the term "job" refers to the basic unit of work that the licensee has defined for the purpose of ALARA planning and work controls. However, since there is no standard definition of a "Job" as used in the ALARA SDP, the licensee can bias the inspection finding SDP outcome by cutting work into finer units.

In addition, since the ALARA finding screening criteria compares actual collective dose experienced in completing a job to the estimated dose projected in the ALARA planning of the job , the licensee can bias the outcome by inflating the projected doses projections. This potential has been recognized since the SDP was developed. It has also been pointed out that the licensee is not required to make a dose estimate (projection) to comply with Part 20. Without an accurate dose estimate the work activity (job) the inspector is left with no clear answer to the Group 2 screening question.

RELATED ISSUES RAISED AT WORKSHOP:

Several of the industry participants stated that they felt the current SDP is overly focused on dose projection or estimates on individual jobs. When this basis for the SDP was challenged as inappropriate, and even outside any regulatory requirement, the NRC staff reminded the participants that Regulatory Guide (RG) 8.8 outlines the NRC's position on an acceptable ALARA program and is part of the licensing basis of each Nuclear Power Plant in operation today. Among other criteria, RG 8.8 specifies that each work activity should have pre-planning and that the exposure to perform the work should be estimated. In developing the current SDP, and Group 2 questions, the staff assumed that each licensee's program was consistent with RG 8.8, and provided reasonably accurate estimates and goals.

OTHER ISSUES RAISED AT WORKSHOP:

Additional issues raised during the facilitated discussion included:

1. One participant felt that the objective listed for the Occupational Radiation Safety Cornerstone conflicts with Part 20 noting that the staff's wording does not exactly match the wording in Part 20 in reference to ALARA.

2. The question of why there is no Performance Indicator (PI) for the ALARA area was raised again at the workshop. Although NEI retains the option of proposing an ALARA PI they tabled the discussion pending the revision of the SDP.

3. Some participants expressed the concern that the current ROP focus on ALARA will lengthen outages and increase total dose. There was a general discussion of whether shorter outages actually lead to lower collective doses or if shorter outages and lower doses were both outcomes of good outage planning and job controls.

4. The level of Radiation Safety inspection effort was raised in the discussions. The NRC staff deferred the discussion on the basis that the staff was in the process of a separate integrated review of inspection effort across all of the ROP cornerstones. Any discussion would be pre-decisional.

OUTCOME OF ISSUES:

The participants at this session of the workshop reached concurrence on the following issues;

1. That the NRC staff should clarify cornerstone objectives, in particular that ALARA is a programmatic requirement in Part 20.

2. The need to make the licensee's rolling three-year average collective dose more contemporaneous.

3. That a single ALARA finding doesn't warrant "yellow" significance and should be removed from the SDP. However,

4. It is appropriate to get to a Degraded Cornerstone in the Agency Action Matrix for multiple White inspection findings.

In addition alignment was reached on a proposed revised approach to assessing ALARA performance (e.g., basis for an inspection finding and SDP criteria). This approach includes consideration of the following actions;

1. Remove the current Group 2, Question 1 (concerning ALARA). Use the rolling three year average collective dose comparison to adjust the baseline inspection level of effort (hours of inspection) and incorporate the other criteria into the baseline inspection guidance.

2. Develop a new basis for an ALARA finding based on the concept of "unintended dose" similar to the current Group 2, Question 2 (i.e., "unplanned, unintended dose(s) that resulted from actions or conditions contrary to.....")

AREAS FOR DEVELOPMENT:

The proposed revised basis for ALARA performance assessment will require additional public meetings with NEI, and other stake holders, to clearly define what "unintended dose" is and how is it identified by the inspector. In addition, the ALARA portion of the SDP would have to be revised to address the magnitude of "unintended dose" along with other criteria. Also, the inspection guidance in this area would have to be revised.

RESPONSE TO QUESTIONS NOT ADDRESSED AT WORKSHOP:

Question: Could NEI 99-02 provide the vehicle for timely reporting of collective dose information to (1) support NRC resource planning needs (as do Performance Indicators in general) and (2) make the information available to the public.

NRC Response: NEI-99-02 defines the Performance Indicator (PI) for the 7 cornerstones. Collective dose and it's implications about ALARA performance is not a PI. ALARA has been specifically excluded from coverage by a PI. However, NEI in recent public meetings has committed to try and provide an acceptable mechanism for making more timely (current) collective does available for use in the ROP assessment of ALARA performance.

CROSS CUTTING ISSUES &
PROBLEM IDENTIFICATION AND RESOLUTION
MEETING MINUTES
(March 26 - 28, 2001)

ISSUE: NO. 1:

Do the performance indicators and baseline inspection program provide sufficient information regarding performance in the cross cutting areas of human performance, safety conscious work environment, and problem identification and resolution (PI & R)?

BACKGROUND:

During the development of the oversight process and during initial implementation, some individuals have expressed a concern that licensee performance in the cross cutting areas of human performance, safety conscious work environment, and PI & R could become degraded without being detected, and that this degradation of performance would be a safety concern.

OUTCOME OF ISSUE 1:

Data obtained from the initial implementation of the revised oversight process (ROP) thus far tend to support one of the fundamental premises of the ROP; that degradation in the cross cutting areas will be detected by either PIs or inspections in a sufficiently pro-active time frame to allow for agency action to protect public health and safety. Examples of where this has been the case are at Indian Point 2, Kewaunee, Millstone, and Cooper. At these facilities, problems have been identified during the initial implementation of the ROP that have been attributed to one of the three cross cutting areas (mainly PI & R) and the NRC has performed supplemental inspections due to PIs and/or baseline inspection findings crossing thresholds. In addition, during initial implementation, there have been no significant precursors to a reactor accident that were caused by cross cutting issues.

ISSUE NO. 2:

Are there other cross cutting issues that warrant additional consideration in the revised oversight process?

BACKGROUND:

During development of the revised oversight process (ROP) and during initial implementation, some individuals have expressed that there may be additional cross cutting issues other than the three identified (safety conscious work environment, human performance, and problem identification and resolution), and that these cross cutting areas are not being adequately addressed in the ROP.

OUTCOME OF ISSUE 2:

No additional cross cutting issues have been identified that would warrant special treatment. There has been a tacit recognition that there are programs, such as the maintenance effectiveness and erosion/corrosion programs, that are essentially elements of a licensee's problem identification and resolution process and thus have cross cutting aspects to them, but not necessarily to the degree they should be called out as an individual cross cutting area.

ISSUE NO.3:

Does the revised reactor oversight process (e.g., inspection program, significance determination processes (SDPs), action matrix) provide for proper treatment of cross cutting issues when they are identified? Should the approach be the same for all cross cutting issues or should the approach vary?

BACKGROUND:

Currently, the revised oversight process (ROP) addresses cross cutting issues by highlighting them in inspection reports when they are notable contributors to inspection findings or if there is an appreciable trend or pattern that has emerged; and in assessment letters to the licensee when they constitute a substantive issue. Recent changes made to Inspection Manual Chapter 0610* better explain when and how cross cutting issues should be documented in inspection reports. The ROP does not allow for additional NRC engagement on cross cutting issues unless they are contributing causes to PIs or inspection findings that are characterized as white or greater. The NRC commissioners have has also directed the staff to specifically inform them if the NRC decides to engage licensees outside of the action matrix because of cross cutting issues. To date, the NRC has not engaged licensees on cross cutting issues outside of the guidance contained in the Action Matrix, as the plants for which significant cross cutting issues have been identified have received supplemental inspection due to performance issues.

OUTCOME OF ISSUE 3:

The results of the initial implementation of the ROP tend to support the above described approach for handling cross cutting issues. As such, additional modifications to the ROP to address cross cutting issues are not currently being pursued; however, the staff will continue to assess events and inspection findings to look for safety significant areas not adequately covered by the current baseline inspections, PIs, or SDPs and to evaluate the adequacy of how cross cutting issues are being handled once identified. During the next year of implementation of the ROP, the following activities are being pursued or considered:

- ASP events and inspection findings classified as yellow or red will be reviewed to determine if weaknesses in one of the three cross cutting areas contributed to the event or finding and whether these weaknesses had been previously identified by either PIs or inspections in a sufficiently pro-active time-frame to allow for NRC engagement. If the weaknesses were previously known, we will evaluate whether the ROP allowed for NRC engagement to protect public health and safety.

- During periodic reviews of issued inspection reports, the staff will evaluate whether cross cutting issues are being sufficiently captured when identified during inspection activities.

- Using the performance metrics developed for assessing the ROP, the staff will review the circumstances surrounding plants that jump two or more columns in the action matrix to see if these performance weaknesses were due to cross cutting issues, and if so, whether inspections or PIs have identified similar concerns.

- During our yearly assessment of the ROP we will evaluate whether the ROP allowed for sufficient NRC engagement at facilities that reached the degraded cornerstone column of the action matrix.

ISSUE NO.4:

Should we change the frequency of the annual problem identification and resolution team inspection?

BACKGROUND

Some individuals have recommended decreasing the frequency of the annual PI & R inspection. The initial results from the first round of inspections would generally support a reduction in frequency. Currently, the baseline inspection program includes approximately 400 hours per year allocated to PI & R reviews. While several inspections conducted during initial implementation of the revised oversight process identified concerns with aspects of licensee's PI & R programs, none of these concerns were determined to have more than minimal risk significance. In addition, licensee's have increased their emphasis on ensuring viable PI & R programs, including increased audits and emphasis on PI & R by the Institute of Nuclear Power Operations. Even with a reduction in frequency in the annual team inspection, PI & R issues would still be assessed periodically throughout the period as part of the baseline inspection procedure attachments. Some of the inspection hours saved could be potentially be used to augment those inspections performed as part of the baseline inspection procedure attachments.

OUTCOME OF ISSUE 4:

The staff discussed a proposed change that would reduce the frequency to once every two years for certain facilities. The staff explained that the frequency would likely be tied to the facilities status in the action matrix, but that the details regarding such an approach have not yet been worked out. An internal workgroup will be formed to assess the frequency of the PI & R team inspection.

OTHER ISSUES RAISED AT WORKSHOP:

Need to consider eliminating human performance as a cross cutting area because of the overly subjective nature of what constitutes a human performance issue.

Need to consider effect of reducing frequency of PI&R team inspection on public confidence.

OUTCOME OF ISSUES

These issues will be considered during future evaluations of cross cutting issues as described above.

PHYSICAL PROTECTION ISSUES
MEETING SUMMARY
(March 26 - 28, 2001)

ISSUE NO. 1:

The IMC 0610*, Appendix B (Thresholds for Documentation), Group 2 question for Physical Protection was unclear.

BACKGROUND:

The past Physical Protection Group 2 question was "Does the issue involve a nonconformance with safeguards requirements?" The term nonconformance, as defined in NRC guidance, is unclear with an unnecessary nexus to regulatory compliance. This rendered the Physical Protection Group 2 question either unusable or open to various other interpretations.

OUTCOME OF ISSUE NO. 1:

The recently revised Group 2 questions were reviewed with workshop participants. The revision objective to clarify the term "nonconformance" was accomplished by establishing new questions that were issued 2/27/01. During discussion industry stakeholders expressed concern that the safeguards Physical Protection Significance Determination Process (PPSDP) was revised without public input. The Staff Requirements Memorandum - COMSECY-00-0036 was distributed to attendees for their review. It was explained that the PPSDP issued on 2/27/01 was an interim document that will be finalized after implementation experience to ensure the objective of the PPSDP are met and applied correctly. Another discussion point was that Group 2, Question 2 would let anything through and did not appear to be an effective filter. Staff will consider this comment in preparing the final version.

ISSUE NO. 2:

The safeguards baseline inspection procedures need to be modified in order to consolidate and clarify baseline requirements, particularly as they relate to force-on-force exercises (OSRE).

BACKGROUND:

During the initial year, the inspection of force-on-force exercises were essentially removed from the baseline Inspection Procedure (IP 71130.03). Direction was given that the force-on-force exercises would continue and be completed using the OSRE IP 81110. Additionally, detailed management guidance was published regarding the conduct of force-on-force (OSRE) inspections that had not been incorporated into the baseline program. Several other comments were received about the other safeguards inspection procedures that had not been addressed in updated procedures.

OUTCOME OF ISSUE NO. 2:

An overview of proposed revisions to the baseline inspection program were discussed and questions answered. The revisions reviewed included changes to the baseline inspection procedures for the Access Authorization Program, the Access Control Program, and the Response to Contingency Events, including an inspection procedure for the SPA pilot program. The revisions would encompass and resolve the concerns from this issue. A concern was raised that these revisions were completed without stakeholder input. The staff will continue to solicit stakeholder involvement as they develop a final version.

ISSUE NO. 3

Revise the current PPSDP (IMC 0609, Appendix E) to incorporate Commission direction contained in COMSECY-00-0036 - SAFEGUARDS PERFORMANCE ASSESSMENT ISSUES ASSOCIATED WITH THE REVISED OVERSIGHT PROCESS, and provide additional objectivity, understandability and predictability to the process.

BACKGROUND:

The use of the reactor safety SDP to evaluate the results of force-on-force security exercises was demonstrated to be unusable in several cases identified during the initial implementation year. The SDP results were inconsistent with the actual risk significance. It was determined that the PPSDP should focus on the evaluation of risk-relevant issues outlined in the Safeguards Cornerstone rather than the PRA-based reactor safety SDP.

OUTCOME OF ISSUE NO.3:

The interim SDP (issued 2/27) was discussed and questions were answered. The staff should address efficacy of the SDP as it is applied. A proposed new PPSDP was introduced and discussed - further stakeholder involvement will be solicited as the staff develops a final version.

ISSUE NO. 4:

Assess the physical protection performance indicators to see whether they clearly accomplish their stated purpose ... “to provide baseline and trend information needed to evaluate each licensee’s physical protection and access authorization systems. The regulatory purpose is to provide high assurance that these systems will function to protect against the design basis threat.”

BACKGROUND:

The adequacy and effectiveness of the physical security performance indicators were identified as an issue of mutual interest during the External Workshop Meeting held on January 10-13, 2000. The potential problems were clearly articulated in the workshop findings (numbers 1g, 1e and 1i). The long term actions of “evaluating alternate PIs” have not been completely addressed.

OUTCOME OF ISSUE NO.4:

The Security Equipment Performance Index PI has an inconsistent performance threshold. NRC staff reviewed the issue with the current method of calculating the performance indicators for safeguards security equipment and proposed changes to the method to ensure consistent application for all sites. In discussion of this, attending stakeholders expressed a unified concern for changing the methods of calculation at this time. The main reasons were that: 1) the difference only effected a few sites (~3) and the indicator would not change the color rating for those sites and 2) the NRC is publishing a proposed rule in the near future and it would be better to wait and review the indicators when the rule was published, allowing for review against the requirements of the new rule. The stakeholders agreed that the performance indicators count compensatory hours versus the equipment availability and that may be grounds for review of the performance indicator criteria, but would like to do it in concert with the proposed rulemaking. Various suggestions about potential changes in performance criteria were discussed, including a general acknowledgment that the other two indicators were weak and should be changed. In regards to the FFD performance indicators, the stakeholders indicated that with the publication of the FFD final rule, a review of those performance indicators could ensue to ensure a nexus with the new requirements.

OTHER ISSUES RAISED AT WORKSHOP:

Should licensee identified findings that are entered in the C.A.P. be run-through the PPSDP? Threshold question?

Ensure SPA Pilot Program follows the current program and revision to 10 CFR 73.55.

Is there data available (aside from current PI data) that would cause the NRC not to need as much inspection?

OUTCOME OF OTHER ISSUES:

These issues will be considered during future evaluations of physical protection issues.

MAINTENANCE EFFECTIVENESS ISSUE
MEETING MINUTES
(March 26 - 28, 2001)

ISSUE:

The significance of 10 CFR 50.65 (a)(4) maintenance rule performance issues cannot be assessed with the existing SDP.

BACKGROUND:

The existing Reactor Safety SDP does not clearly address issues related to risk assessment and risk management associated with performance of maintenance activities. The existing SDP phase 1 worksheet may inappropriately screen risk-significant plant maintenance configurations to “green.” In addition, the phase 2 site-specific inspection notebooks lack the necessary level of detail and completeness to assess maintenance configurations with multiple equipment out-of-service. The licensees are already using phase 3 type analyses (and tools) to assess the at-power risks of maintenance configurations.

OTHER ISSUES RAISED AT WORKSHOP:

1.Treatment of past (a)(4) evaluations that increase in significance from a PRA upgrade or correcting a PRA deficiency?

2. Is there a need for an SDP for (a)(1), (a)(2), and (a)(3)?

3. Will the NRC issue an (a)(4) violation for “failing to manage risk” when issuing a violation for “failing to adequately assess the risk”?

4. Proposed (a)(4) SDP process could have an unintended consequence: cause licensee to make its risk management guidance vague.

5. Licensees with more sophisticated PRA models may be penalized compared to licensees with simple IPEs.

6. Proposed (a)(4) SDP process would be an additional burden to the licensee.

7.Consider using loss of key safety functions for both Power & Shutdown (a)(4) SDPs

The proposed draft SDP discussed during the workshop is attached.

OUTCOME OF ISSUE:

Session participants agreed that the NRC needs to continue developing the SDP (a)(4) process and work closely with stakeholders in resolving the above issues 1, 3, 4, 5, 6 and 7.

The NRC's maintenance effectiveness focus group had previously reviewed issue no. 2, raised during the workshop, and had concluded that the existing reactor SDP was adequate for determining the significance of maintenance rule (a)(1), (a)(2), and (a)(3) equipment performance issues. However, the focus group recommended that additional guidance be added to MC 0610* to clarify documentation requirements for (a)(4) issues. This will be incorporated in MC 0610* after the (a)(4) SDP is finalized.

RESPONSE TO QUESTION NOT ADDRESSED AT WORKSHOP:

Question: Could you consider using a flow chart approach similar to the draft SDP for radioactive material control program for evaluating the significance of "failure to manage risk" issues?

NRC Response: We will consider a blended approach (quantification and flow chart) for assessing the significance of (a)(4) performance issues. We will continue to work closely with stakeholders in developing the SDP for (a)(4).

ASSESSMENT AND ENFORCEMENT ISSUES
MEETING MINUTES
(March 26 - 28, 2001)

ISSUE NO. 1:

The role of no color findings in the oversight process is not clear and has contributed to program inconsistencies.

BACKGROUND:

The staff has received feedback from external stakeholders throughout initial implementation of the ROP that the role of “No Color” findings in the oversight process is not clear and has contributed to program inconsistencies. There was also some concern that the existence of “No Color” findings represented a weakness in the ROP. “No Color” findings are associated with specific extenuating circumstances as discussed in IMC 0610* “Inspection Reports”. Early guidance to the regions was non-specific which resulted in the significance of these findings being confusing to stakeholders and their role in the assessment program was unclear. Clarification to existing program office guidance appears to have reduced the number of “No Color” findings. The assessment program was not designed to include “No Color” findings and their existence may undermine public confidence in the ROP.

The staff’s intention was that “No Color” findings are greater than minor findings of a regulatory nature (e.g., do not impact a cornerstone) that can not be evaluated by the current SDP. These findings should only include violations of regulatory requirements or notable adverse performance trends or patterns associated with cross-cutting issues. These findings are expected to be small in number.

OUTCOME OF ISSUE:

The goal of this session was to provide a proposed solution followed by a group discussion of the proposal. The workshop participants could not reach consensus on the staff’s proposal to color these findings as green. Some of the participants were concerned that the proposal would give the appearance that these findings had been evaluated through the SDP and had the same risk significance as other Green findings. As an interim measure, the group recommended that the agency: (1) address the perception problems with “No Color” findings, (2) continue to monitor “No Color” findings and adjust program office guidance to minimize the number of these findings, and (3) evaluate these findings to determine if they represent a weakness in the ROP. Over the longer term, the staff will also evaluate the role of “No Color” findings in the ROP.

ISSUE NO. 2:

There is some confusion regarding the purpose of a regulatory conference and a regulatory performance meeting.

BACKGROUND:

The purpose of a Regulatory Conference is to gain a complete understanding of the significance of an inspection finding as well as information pertinent to understanding any apparent violations. In some cases, this requires a technical discussion of the probabilistic inputs and assumptions used to characterize the risk significance of the issue. The role of NRC and licensee management has changed from their role during enforcement conferences held in the past. The Regulatory Conference was not intended to be a forum for a discussion of the adequacy and effectiveness of licensee corrective actions. However, a significant amount of attention has been devoted to the discussion of licensee corrective actions during Regulatory Conferences. This may be due in part to the efficiency in conducting a detailed discussion of corrective actions at this meeting in conjunction with a discussion of the significance of an inspection finding and any apparent violations.

OUTCOME OF ISSUE:

The staff proposed that the guidance in IMC 0609, attachment 1 be revised to more accurately characterize the purpose of the meeting and to clearly differentiate it from the Regulatory Performance Meeting.

Licensees are normally offered an opportunity for a Regulatory Conference to discuss potentially safety significant inspection findings, whether or not violations are involved. A secondary purpose of the meeting is to provide an opportunity to address any apparent violations that may be associated with the finding. This meeting enables the agency to obtain the licensee's perspective in order to come to a common understanding of the facts and the significance of the findings. The Regulatory Conference is not a meeting to negotiate sanctions or discuss the adequacy of any current or proposed licensee corrective actions. If a licensee is in agreement with the issues then they may opt not to have a Regulatory Conference.

Regulatory Performance Meetings are held between licensees and the agency to discuss the effectiveness of a licensee's root cause evaluation and corrective actions associated with safety significant inspection findings after the completion of the associated supplemental inspection. Each safety significant assessment input shall be discussed in one of the following forums listed below in order to arrive at a shared understanding of the performance issues, underlying causes, and planned licensee actions. These discussions may take place at supplemental inspection exit meetings between the agency and the licensee, conference calls, or public meetings. This meeting should be documented in an inspection report or a public meeting summary as appropriate. NRC management, as specified in the Action Matrix, conducts the Regulatory Performance Meeting.

The participants generally agreed to the staff's proposal and provided the following recommendations: (1) due to possible public perception problems, the licensees should be allowed to address corrective actions after the discussion of safety significance and any apparent violations at the Regulatory Conference, (2) someone other than the regional enforcement coordinator should open the meeting, and (3) the Regulatory Conference should be chaired by the appropriate level of NRC management (e.g., in accordance with the Action Matrix). Licensees also recommended that the NRC standardize the process for sharing the basis and assumptions of safety significant findings prior to the Regulatory Conference.

ISSUE NO. 3:

What are the appropriate actions for a plant that has a safety-significant PI that re-enters the green band even though the licensee's response, relative to its root cause evaluation of the issue, is inadequate?

BACKGROUND:

IMC 0305 states that an inspection finding is normally carried forward in the assessment process for a total of four calender quarters. There is a provision that an inspection finding will not be removed from consideration of future agency actions (via the Action Matrix) until the identified weaknesses in the root cause evaluation have been corrected by the licensee. There is no such provision for safety-significant performance indicators. However, it is appropriate that the original performance deficiency (whether it is an inspection finding or a PI) will not be removed from consideration of future agency actions (i.e. the Action Matrix) until the licensee has corrected the issue.

This situation occurred last year at Kewaunee Nuclear Station last year. The licensee's evaluation of a yellow Alert and Notification System PI was determined to be inadequate after two supplemental inspections were conducted on this issue. In this case, the regional staff issued a parallel yellow inspection finding that corresponded to the original performance deficiency from the yellow PI.

OUTCOME OF ISSUE:

The goal of this session was to solicit licensee input and arrive at a consensus approach. Entering into the workshop, the staff proposed that a parallel inspection finding may be issued when the corresponding supplemental inspection procedure for a risk significant performance indicator reveals substantive inadequacies in the evaluation of the root cause of the original performance deficiency, the extent of performance problems, or the associated corrective actions. The agency asked the workshop attendees to provide their input on several implementation issues in applying this approach such as:

- ! How much of an opportunity (if any at all) should be provided to the licensee to correct the deficiencies in the evaluation prior to the issuance of the parallel inspection finding.

- ! What criteria should the agency consider in evaluating whether a parallel inspection finding should be issued.

- ! How to provide licensees the opportunity to provide their perspective on the identified weaknesses prior to issuance of the proposed parallel finding.

- ! Whether the finding is a placeholder for the original performance deficiency or a separate finding directed against the Corrective Action Program (CAP) that would require a separate evaluation and corresponding supplemental inspection. This question would apply whether the original performance deficiency was an inspection finding or a performance indicator.

- ! The appropriate time and method to remove the inspection finding from consideration in the assessment program.

The participants in the workshop were in alignment on the following implementation issues:

- ! The performance issue should remain open. The NRC should open a finding of the same color as the original performance issue and be considered as a finding against the corrective action program.

- ! There should be a strong casual link between the original performance deficiency and the ineffective corrective actions in order to issue the parallel inspection finding.

- ! The licensee should be provided an opportunity to provide input at the supplemental inspection exit meeting.

Consensus was reached that the finding should be removed once the appropriate corrective actions have been completed. The agency will add additional programmatic guidance on how to address supplemental inspection for performance indicators when there are substantive inadequacies in the evaluation of the root causes of the original performance deficiency, the extent of the performance problems, or the associated corrective actions.

ISSUE NO. 4:

How should historical issues that have safety significance but are not reflective of current performance (e.g., Oconee design issue) be addressed in the oversight process.

BACKGROUND:

The assessment program determines appropriate agency actions based upon the most current licensee performance. The most current licensee performance is determined on a quarterly basis by reviewing the current PI and inspection results. The date used for consideration in the assessment program is the date of the end of the pertinent inspection period for the finding. Historical issues, such as those that are captured during design inspections, are not necessarily reflective of current licensee performance. In particular, those issues already identified by and appropriately addressed by the licensee would be reflective of good licensee performance.

OUTCOME OF ISSUE:

During the session the staff asked the participants to consider the following three fundamental questions when considering historical issues in the reactor oversight process:

- Whether the ROP should be reflective of current **plant** conditions or current **licensee** performance.

- What types of issues would not be considered reflective of current **plant** conditions or **licensee** performance.

- Can the approach for treating historical issues be structured such that it does not create disincentives for licensees aggressively seeking to identify and resolve issues.

The consensus approach from the breakout session was that an issue with current risk significance is a performance issue, regardless of whether it reflects current licensee organizational performance. Consensus was not reached on whether to treat this finding like all other findings in the assessment process or whether to define a class of findings that may warrant discretion. The agency will consider the development of further guidance that would describe the types of issues that may be considered for deviations from the Action Matrix.

COMMUNICATION ISSUES
MEETING MINUTES
(March 26 - 28, 2001)

ISSUE 1:

To what degree and how should NRC consider incorporating public feedback into the Reactor Oversight Process (ROP).

BACKGROUND:

Some stakeholders are unclear on how feedback they provide the NRC on the ROP is considered. The NRC's current feedback process allows for incorporating public feedback, but this is not well understood.

ISSUE 2:

Some stakeholders have expressed concern that the NRC's Significance Determination Process results in negotiations between the NRC and licensee that are not done in a public way.

BACKGROUND:

Existing guidance requires information that is considered by NRC to be docketed or at least referenced in inspection reports.

ISSUE 3:

The ROP WEB site has been developed to provide greater access to key plant performance and ROP related information. Refinements have been made over the year to improve the content.

BACKGROUND:

A substantial WEB Site has been established to disseminate information to the public. This site provides information on plant performance and reactor oversight related guidance and information. Feedback has generally been very positive but some negative feedback has been received.

ISSUE 4:

Having a public Annual Assessment Meeting may not be effective and efficient application of NRC and licensee resources.

BACKGROUND:

A. Some stakeholders have observed that if a plant is in the licensee response band (All Green) why do we need to conduct an annual meeting with the licensee?

B. Current approach should be augmented so that the NRC can effectively interact with the public.

ISSUE 5:

Some NRC staff are reluctant to provide insights beyond what is documented in inspection reports because of the changes in reporting threshold and lack of guidance in this area.

BACKGROUND:

Manual Chapter 0610* raised the threshold for documenting by eliminating minor findings, Inspector observations, licensee identified findings (not violations), weaknesses and positive findings, and removed non-regulatory issues

OTHER ISSUES RAISED AT WORKSHOP:

Some stakeholders believed that the cost of complying with some regulations is not commensurate with the risk significance or benefit derived from complying with these regulatory issues.

Some stakeholders believe that as an area for improvement, the NRC should clearly describe the term "significance" referring to the basis for Significance Determination Process result.

It was requested that the NRC consider a WEB site for decommissioned plants.

It was suggested that the NRC establish a feedback process on Reactor Oversight Process for licensees.

OUTCOME OF ISSUES:

NRC has developed, as part of it's interval feedback process, an approach to address input received from external stakeholders. Issues or concerns raised by external stakeholders are considered for input into the NRC's internal feedback process. If a change to ROP guidance or implementation documents is possibly warranted, the feedback will be captured on a feedback form, the stakeholder will be informed of how we intend to address the issue or concern, and then when a final determination is made, a closure letter or email response will be provided.

Additionally, for major feedback evaluations, such as responses to Federal Register Notices, it was recommended that the staff develop a matrix, or similar device, that will represent feedback received and how it was considered in the process. The staff is developing a Commission paper that provides an analysis of feedback obtained and lessons learned from the first year of implementation of the ROP. As an attachment to the Commission paper, the staff will develop a summary of the comments provided in response to the current FRN seeking comment on the ROP. When issued, the commission paper will be made available on the external web.

While the NRC clearly described how it's process results in documenting Significance Determination Process (SDP) related activities and information, it was noted that many times the findings documented in inspection reports do not clearly describe how the SDP was applied, or when a licencee's analysis was applied to the final significance, why it was better then the NRC's analytical approach. These are issues that the NRC is continuing to improve to make the process more understandable.

An issue was raised regarding the availability of licencee PRA's or at least a publically available standard so that the public could have a greater degree of confidence in the results of a risk analysis. This is an issue that goes beyond the ROP and is a matter of ongoing discussion with the agency through its PRA-related activities.

The NRC staff will consider recommended enhancements to ROP WEB page, eg., "Bottom-line" first, easier navigation to details, plain language in narratives, and will consider suggestions on responding better to public comments on ROP.

The NRC staff will also consider ideas for public interaction in conjunction with the annual assessment meeting with each licensee.

During a discussion related to the significance thresholds for documentation in inspection reports, there was no consensus reached on documenting observations or minor violations, nor was there a consensus on whether an annual meeting with the licensee should be conducted as part of an annual assessment for "all green" plants.

The NRC staff will incorporate guidance on providing inspector insights beyond the inspection report into manual chapter 2515 and into NRC inspector training program .

Compliance with NRC regulations is still a important element of the agency's regulatory framework. While moving into a more risk-informed regime provides insights regarding the relative risk significance of various regulations, it is the clear expectation of the NRC that licensees will comply with the regulations.

A WEB site for inspection reports for decommissioned plants does not currently exist. However, inspection reports for these plants can be obtained via ADAMS. As part of the agency's communication initiative, staff will continue to evaluate the need for such a site.

The NRC already has a number of processes that engender and report to industry feedback, such as the ROP's FAQ process for Performance Indicator issues and the regulatory input process for collecting feedback obtained by agency managers during site visits. However, the NRC, as part of it's ongoing interactions with industry's ROP Working Group will pursue development of an appropriate feedback process for other ROP related issues if one is warranted.

RESPONSE TO QUESTIONS NOT ADDRESSED AT WORKSHOP:

Question: The Manual Chapter 0610* Group 1,2 and 3 questions are very subjective.

NRC Response: The Group 1 questions were derived from the NRC Enforcement Manual which describes what constitutes a Minor Violation. This same guidance applies to "issues" or "Findings" in the Reactor Oversight Process. Additionally MC0610* requires that the Group 1 questions be used with the Office Of Enforcement (OE) "Guidance for Classifying Violations as Minor" when the inspector is not clear whether a issue is minor or not. The OE guidance provides 45 very specific examples to help guide the inspector in his determination.

The Group 2 questions are very specific questions to determine whether an issue could be analyzed by the SDP and affects a cornerstone. Each question is derived from the specific discipline area of expertise within the NRC, i.e. Security and Safeguards, Emergency Preparedness, Fire Protection, etc.

The Group 3 questions were again derived for the NRC Enforcement Manual for issues which could not be analyzed by an SDP but were of such a high significance that they should be sent directly to OE for assignment of a severity level. However, one question regarding cross-cutting issues was added to allow the regions to track significant trends associated with cross-cutting issues which were related to SDP analyzed findings.

Question: Have NRC inspectors been given any guidance or set of objective criteria with which to answer the questions?

NRC Response: Manual Chapter 0610* "Inspection Reports" provides guidance to the inspectors on how to use the above questions. Additionally, examples of minor violations are provided to the inspectors on the NRC web-site under the Office of Enforcement, Guidance Documents, Appendix A, Index, "Guidance for Classifying Violations as Minor Violations".

Question: Inspectors do not document their logic for driving issues through tables 1 and 2 to the SDP which ultimately results in a Green NCV just because the issue was evaluated by the SDP. Why?

NRC Response: We are finding that some NRC inspection reports are still not in full compliance with Manual Chapter 0610* which requires that inspectors document "a more detailed significance evaluation paragraph that describes the logic for entering the SDP ". However, to further emphasize the requirement, the next revision to Manual Chapter 0610* will state "Each inspection finding must have a description of the decision logic used to determine the significance color of the finding in sufficient detail to allow reconstruction of that logic." However, most recent inspection reports are now coming into compliance with MC0610* and are providing more details regarding the logic for their determinations. NRC headquarters is currently conducting reviews of inspection reports and compliance with the requirements of MC0610* and provides feedback to the inspectors supervisors.

Question: Is NRC considering changes to MC0610* group 1 and 2 questions to eliminate subjectivity? If not, why not?

NRC Response: The NRC is considering making changes to the Group 2 and 3 questions but not to Group 1 nor to eliminate subjectivity. The questions are designed to cover a broad base of situations and cannot be specific to each and every activity, therefore must be somewhat subjective . The NRC will consider any specific suggestions to help remove the subjectivity from any of the Group questions.

Question: The screening criteria used to determine if the SDP should be used or not is too subjective, i.e. , it is too easy to take a finding into "SDP-Space" with the automatic outcome / result being a Green / No -Color NCV

NRC Response: All results of the SDP are based on several sets of screening questions used to determine the significance of the inspection findings. The NRC has developed a set of screening questions that have been in place for several years in the NRC enforcement policy which separate out issues of minor significance. Additionally, the SDP phase 2 analysis provides a set of screening questions for which most issues analyzed do not meet and therefore, most issues analyzed result in a very low significance (Green). The NRC recognizes that the Green bin of issues is the widest category of issues, but also feels comfortable that the current set of screening questions will capture significant issues and adequately screens out minor issues.

RESPONSE TO MISCELLANEOUS QUESTIONS NOT ADDRESSED AT THE WORKSHOP

Question: 1) Statement was made that licensee's challenge of "Green-NCV" issues is a concern to the NRC, 2) NCV-expectations is to handle issue in licensee corrective action program, 3) Potential Unintended Consequence - What happens if the licensee determines that no corrective action is warranted? Is the NRC willing to accept this response? Is there still a need to restore compliance if the licensee has determined there is no violation? It does not seem prudent not to engage the NRC in some fashion on these issues.

NRC Response: Licensee's must take corrective actions to restore compliance for conditions that constitute a violation of the regulations.

The NRC Enforcement Policy indicates that for Severity Level IV violations and violations associated with green Significance Determination Process (SDP) findings are normally dispositioned as non-cited violations (NCVs) for power reactor licensees. This enforcement approach places a greater reliance on licensee corrective action programs because an NCV does not require the licensee to provide a written response describing the actions taken to restore compliance and prevent recurrence of the violation.

The External Stakeholder Workshop on the reactor oversight program (ROP) included a panel discussion to address assessment and enforcement issues. During this discussion, an NRC panelist indicated that the NRC was spending an inordinate amount of time entertaining arguments from licensee's regarding green findings that are associated with violations. Typically, these arguments involve the licensee's assertion that the issue is minor in nature and, thus, neither the violation nor the finding should not be documented in an inspection report. In either case, the licensee would still be required restore compliance. The NRC is concerned about the resources expended discussing the threshold separating minor violations from Severity Level IV violations and violations associated with green findings with licensee's because the time expenditure is inconsistent with the risk significance of the issue.

A formal dispute process exists to address cases in which the NRC identifies a condition that is determined to constitute a violation and the licensee disagrees with the NRC's position. If the NRC review upholds the licensee's position, no corrective action is required because the NRC has concluded that the existing configuration satisfies agency regulations.

An exemption from the regulations can be requested to address a condition in which both the licensee and the NRC agree that a violation exists but restoring compliance would constitute an unnecessary regulatory burden. The NRC could grant the exemption which would accept the nonconforming condition if it was determined that the condition will not present an undue risk to the public health and safety and is consistent with the common defense and security as described in 10 CFR 50.12, "Specific exemptions."

Could the licensees use the very low safety significance definition of a green finding as a bases for eliminating costly or complex corrective actions for issues that were documented as NCVs? This would be analogous to licensee's granting themselves exemptions from the regulations based on their own risk evaluations. This position is not acceptable under the regulatory framework used to license power reactors. The agency response to this condition would likely result in the issuance of a cited violation which would require the licensee to submit a written response detailing the actions taken to restore compliance and prevent recurrence of the violation.

Question: In the NEI opening remarks, crediting licensee self-assessment was identified as a potential opportunity for unnecessary regulatory burden. 1. What consideration is being given to explicitly crediting licensee self-assessments in lieu of inspection in the ROP? 2. What consideration is given to a change in inspection guidance/practice to finalize the inspection scope 3-4 months in advance of a fire protection triennial or SSDI inspection and to communicate it to the licensee so that the licensee has the opportunity to perform it's own self-assessment and share the results with the inspector for their consideration prior to or at the start of the inspection?

NRC Response: Inspections along with performance indicators provide the input to the new ROP that enables the NRC to evaluate the safety performance of licensees and identify appropriate NRC and licensee actions to follow up on performance concerns to ensure they are addressed. The inspection program, as revised to support the ROP, identifies requirements that must be accomplished by NRC personnel. In order to effect a smooth transition to the ROP and to enable the staff to gain experience with its implementation, consideration was not given during the first year to crediting licensee self assessments in lieu of NRC inspection. With completion of the first year of implementation, the NRC intends to begin considering ways in which licensee self assessments could be utilized to supplement or replace NRC inspection in limited, selected areas. Use of NRC self assessments would be considered in those instances where NRC and licensee safety effectiveness and efficiency would be enhanced and public confidence would not be diminished.

NRC baseline inspections, especially the team inspections, are planned well in advance, although the specific scope of the inspections may not be determined until shortly before the inspection.
As discussed above, the NRC plans to evaluate what role licensee self-assessments could play in the ROP and if that role affects baseline team inspections the agency would need to identify inspection scopes earlier in the planning.

Question: In the inspection manual each inspection procedure has an estimated number of hours for inspection listed. Very rarely does the inspection come close to the hours listed. Usually, actual hours charged are 1.5 times greater. Example: PI&R inspection listed as 210 inspection hours (~$30K). Brunswick PI&R actual hours charged-346 (~50K). This makes it very hard to create a realistic budget. When the senior resident and branch chief were asked about the number of hours charged the response was only hours worked on site are reflected in the inspection manual. Preparation hours and hours writing the inspection are not included. Question: Is it possible to provide an actual number of hours/inspection to allow accurate budget preparation?

NRC Response: Estimates on how long an inspection (on-site) activity should take are provided only to assist the regions in resource planning. Currently, the ROP assumes a 1:1 planning/documentation to inspection activity ratio. That is, if the inspection is estimated to take 40 hours, another 40 hours of inspection effort to plan for and document the results of the inspection can be expected. During the first year of initial implementation inspectors were encouraged to complete the inspection requirements and document the time expended and not overly focus on the time estimates. The staff is currently analyzing the data from the past year of inspection to refine its estimates on conducting the inspection, including planning and documentation. While these estimates will provide for an effective planning tool, individual plants may review more or less inspection in a particular area due to factors such as complexity of issues, retrievability of information and inspector experience and expertise.

Question: At the opening session a slide was presented that showed number of plants versus inspection hours. Have inspection hour data been assessed with respect to Average Inspection Hours per plant–single unit versus multiple unit sites? My concern is that single unit sites, on average, (given all of the other factors are similar) receive more inspection hours then a plant at a multiple unit site.

NRC Response: The current inspection model provides for increasing level of inspection at single, dual, and triple unit sites. While multi-unit sites will receive more overall inspection then a single unit site, a single unit site will receive more inspection on a inspection hours to unit measure then an individual unit at a multi-unit site. This is a reflection of the ability to translate many of the findings and insights determined by inspection activities at any of the units at a multi-unit site due to the common programs, processes, and personnel.